

UOGM

Unconventional Oil & Gas Monitor

Issue 445

26 • February • 2019

Week 08



Liquid assets

A new find in China has led to speculation that shale oil can be commercially viable in the country, but output is unlikely to reach the levels seen in the US.



Permian profitability

Larger producers in the Permian Basin are more likely to turn profits from their wells even at lower oil prices.



CBM spat

A disagreement between PetroChina and Royal Dutch Shell is reportedly holding up development of their joint CBM acreage in the Surat Basin.



Midstream sale

Targa Resources is selling a 45% stake of its Bakken pipeline assets in a US\$1.6 billion deal with two private equity firms.





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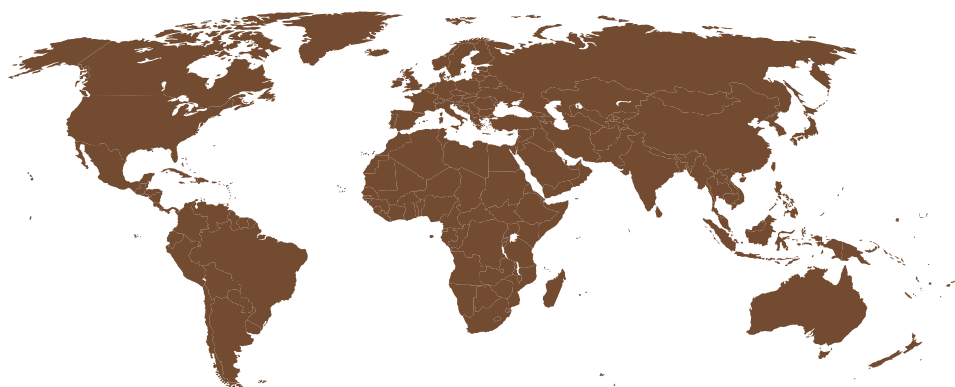
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Argentina's new conundrum: too much gas

After years of gas shortages, Argentina faces an oversupply. This means it must grow its local market, expand exports and cut imports, writes Charles Newbery in Buenos Aires

ARGENTINA

WHAT:

Gas output hit 47 bcm last year, meaning the country has an occasional oversupply.

WHY:

Rapid development of the Vaca Muerta shale plus limited export infrastructure and ongoing imports have caused the imbalance.

WHAT NEXT:

The country has nascent LNG export capacity and is working to expand piped gas exports to its neighbours.

A few years ago some energy sector leaders in Argentina began warning the country could soon face an oversupply of natural gas.

Their concerns caused bemusement and were widely dismissed. The country was still emerging from a decade of gas shortages after production plummeted by 20% to a 16-year low of 114 mcm per day (42 bcm per year) from a record high of 143 mcm (52 bcm).

This decline forced the authorities to halt 20 mcm per day (7 bcm per year) of exports to Brazil, Chile and Uruguay in 2004, and turn to Bolivia and the global spot market to hedge against supply shortfalls during the cold winters. Imports reached 32 mcm per day (12 bcm) in 2017 and held at 27 mcm (10 bcm) in 2018, with about 60% coming in by pipeline from Bolivia and the rest as LNG from suppliers such as Australia, Qatar and the US.

This helped abate the shortages, which have narrowed to periods of maximum demand during the winter months.

But domestic output has rebounded sharply, the game changer being the industrialisation of the Vaca Muerta shale. This saw Argentina's gas output expand by 13.3% between 2014 and 2018 to reach 129 mcm per day (47 bcm). While still shy of the 143 mcm per day (52 bcm) record in 2004, the increase has led to periods of oversupply when local demand dips in the warmer months from October to April.

State-run YPF, the country's biggest gas producer, had to shut in some wells, including in the Vaca Muerta, in the second half of 2018 because it could not offload all of its output. YPF and other producers in the play have started to shift their investments to the oil window because it is easier to sell crude domestically and internationally.

Meanwhile, the government and private companies have been taking steps not only to expand the market for Vaca Muerta gas, but also to extend the infrastructure needed to get it out of the southwestern shale play.

New Bolivian deal

These efforts are now starting to pay off.

On February 14, Argentine Energy Secretary Gustavo Lopetegui completed negotiations to import less gas from Bolivia in the summer and more in the winter, a proposal that had been on the cards for more than a year.

La Paz had been negotiating to keep the contract unchanged until its expiration in 2026, as gas exports are a major source of tax revenue and dollar inflows. Bolivia exports most of its 60 mcm per day (22 bcm per year) of output to Argentina and Brazil.

With the new deal, Argentina will buy less in the warmer months over the next two years, enabling it to sell more from the Vaca Muerta. "At present, we have exportable gas surpluses in summer, but we still require imports in winter," Lopetegui said in a statement.

As part of the deal, Buenos Aires will not have to pay penalties for importing less than is stipulated in the contract, saving it an estimated US\$460 million in 2019 and 2020, the energy department said.

In order to make the deal, Argentina conceded to pay higher prices for the supplies, and also to give Bolivia an aeroplane in lieu of unpaid penalties for 45 mcm that was not imported between May and September of 2018.

Under the amended contract, Argentina will import more gas during June, July and August, and less during the rest of the year. Bolivia will deliver 11 mcm per day between January and April and between October and December, 16 mcm per day in May and September, and 18 mcm per day between June and August.

While Bolivia will deliver less than the 20 mcm per day (7 bcm) it was supplying in 2018, it will offset some of the losses by charging a higher price. Bolivian Hydrocarbons Minister Luis Alberto Sanchez said he anticipated the amendment would boost the country's revenue on gas sales by around US\$450 million compared with 2018, when also considering exports to Brazil. ►►

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YPF had to shut in some wells, including in the Vaca Muerta, in the second half of 2018 because it could not offload all of its output.



Exmar's Tango FLNG vessel arrives in Argentina.

➤ Sanchez said Argentina would pay US\$7.18 per mmBtu for gas in the months of low consumption, up from an average price of US\$6.28 per mmBtu in 2018.

In the months of higher consumption, Argentina will pay around US\$10.3 per mmBtu, a price based on global LNG reference prices plus an extra sum related to regasification fees. This is a change from previous contracts when the price was based on West Texas Intermediate (WTI) crude.

"It has been a great negotiation because we managed to increase the price by 15% in summer," Sanchez said. "In winter, we have the LNG price plus a percentage of the cost of regasification. Remember that LNG is always US\$3 to US\$4 higher than the price indexed to WTI. That's why this price is historic. Because we never had a better price."

Expanding exports

While the deal reduces gas imports, Argentina simultaneously aims to expand exports to help drive production growth.

In February, YPF brought in the country's first floating LNG terminal to enable it to sell waterborne supplies to the global market. The FLNG terminal is being installed in Bahia Blanca, Buenos Aires province, and is due to start exporting in the next few months.

The government also held a tender last week for exporting gas to Uruguay.

This will facilitate the extension of piped gas deliveries beyond Brazil and Chile, which started buying Argentine supplies again last year.

Eleven companies submitted bids and the winner, which was not been named yet, will sell 400,000 cubic metres per day at a price of US\$3.77 per mmBtu to Ancap, Uruguay's state-run oil company, between March 1 and April 26, 2019.

Though exports are being scaled up, there have been some hiccups along the way. Last week, the government had to suspend temporarily 5.8 mcm per day of exports to Chile, redirecting the supplies to meet local demand during a heat wave. The supplies were rerouted to power plants to meet a surge in demand for air conditioning.

The lack of warning for this diversion annoyed gas producers, with the government acknowledging it would give more advance notice next time.

The government also intends to expand gas infrastructure with a view to pushing up domestic sales and has issued a decree opening up the midstream sector to more players to operate oil and gas pipelines.

This will help to grow the transport capacity that underpins the development of the Vaca Muerta, Carlos Casares, the deputy secretary of hydrocarbons, said in a statement. The next big project on the slate is the construction of a new backbone pipeline to export gas from the shale play, which will be built in tandem with the expansion of existing lines.

There is considerable momentum in the sector, despite the country's poor economic climate. And the driving force is something many did not foresee a short while ago: too much gas. ♦

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Argentina has completed negotiations to import less gas from Bolivia in the summer and more in the winter.

Jimsar find boosts Chinese shale oil prospects

A new find in China has led to speculation that shale oil can be commercially viable in the country, but production is unlikely to reach the levels seen in the US, writes Kevin Godier

CHINA

WHAT:

Shale oil drilling could have commercial potential in China.

WHY:

PetroChina is producing oil from the Jimsar shale field in western Xinjiang.

WHAT NEXT:

There is speculation that Chinese shale oil output could hit 200,000 bpd by 2025.

THE world's top crude importer, China, may be one step nearer to commercially viable shale oil, following a discovery in its northwestern region, according to investment bank Morgan Stanley.

PetroChina achieved production of 733 bpd at a test well in the Jimsar field in Xinjiang Province, suggesting that shale oil has strong commercial potential in the country for the first time, Morgan Stanley said in a February 18 note. "We believe the Jimsar shale oil discovery is likely to trigger China's shale oil revolution," a Morgan Stanley analyst, Andy Meng, wrote in the note. "We expect a further capex rise in 2019, which could make onshore oilfield services names the key beneficiaries," he added.

The investment bank has projected that the shale field could generate output of 100,000-200,000 bpd by 2025. If this can be achieved, it will help limit the dependence of the world's second largest economy on crude oil imports – which are often geopolitically charged.

The Jimsar discovery comes as China's biggest oil and gas producers have recently started to tap more tight oil and gas wells – including in formations that are not shale. These efforts form part of a government push to boost domestic energy supply, on the orders of Chinese President Xi Jinping.

State-owned players China National Petroleum Corp. (CNPC) and Sinopec have both

increased their spending on raising domestic oil and gas output. Both companies said in 2018 that they had accelerated their drilling activity at tight oil and gas formations in western China.

Evolution

China's national oil companies (NOCs) are in the process of developing their technology and techniques to produce oil and gas from more challenging rock formations such as shale.

While Jimsar is China's first significant shale oil find, the country has experienced some success in producing shale gas over the past 10 years. The evolution of the shale industry has been slow, however, to some extent owing to restrictions that have limited exploration and drilling to the NOCs. Equally significantly, China's shale reserves are mostly located at considerable depths – which are much greater than those of shale plays in the US. These plays are often found in remote, mountainous regions that lack pipeline and transportation infrastructure, and abundant sources of water. This makes it more costly to develop the sites and ship equipment and materials in – or production volumes out – as well as to maintain well integrity.

China also lacks some of the other factors that have helped drive the US shale boom. Notably, these include open markets that promote competition, a network of independent services





Challenging terrain and a lack of infrastructure are among the stumbling blocks for Chinese shale development.

- companies that push innovation in areas such as hydraulic fracturing and locally available expertise.

Reserves are nonetheless plentiful, with the US Energy Information Administration (EIA) estimating that China has nearly twice as much shale gas as the US. Output is an entirely different picture, with EIA data showing that the US produced about 639 bcm of shale gas in 2017, as against about 9 bcm in China.

A significant leap for shale oil would therefore be particularly welcome for China, which has seen its crude output decline since 2015 owing to the depletion of mature conventional oilfields. The drop has come at a time when Chinese political leaders have persistently talked up the benefits of energy self-sufficiency.

Illustrating the problems, CNPC said in late 2018 that the drilling cycle at its Mahu field in Xinjiang, one of the company's largest finds in recent years, had fallen by around 40% in 2017. A Reuters report said this implied that oil wells were being completed and tapped at a faster rate.

Meanwhile, oil demand continues to grow in China. In 2018, the country's refineries processed 12.07 million bpd on average, up by 6.8% year on year, and marking the highest daily processing rate on record. Nomura's head of greater China energy global markets research, Lin Chen, said in a January research note that crude imports to the country could rise further in 2019, to 9.5 million bpd, up more than 4% from the previous year.

What next?

A few years ago, talk of a Chinese shale revolution prevailed as the country's fast-growing demand for energy sparked enthusiasm over the prospects for tapping its unconventional reserves. Then the hype faded as the challenges involved became clearer and initial output fell short of expectations.

China's ambitions to develop more of its own oil and gas reserves can easily be viewed as a race against a ticking clock. A large proportion of the country's oil imports come with geopolitical caveats attached. Above all, China is the largest importer of Iranian oil, which is running up against renewed US sanctions that kicked in on November 5. China is also reliant on crude imports from Russia, which is also operating under tougher US sanctions.

Even with the Jimsar find, *NewsBase Research (NBR)* believes it is unlikely that China will be able to scale the heights of US shale, which accounts for over half of US oil production now. The EIA projects that the seven leading shale regions in the US will produce 8.31 million bpd of tight oil in February, and 8.40 million bpd in March, marking a month-on-month increase of 84,000 bpd.

However, even without a similar acceleration in Chinese shale oil output, higher spending and revenue boosts can be expected for the oilfield service companies that will be brought in to drill unconventional formations.

Morgan Stanley has suggested that Yantai Jereh Oilfield Services Group, whose stock market value is up 31% this year, and SPT Energy Group, which has enjoyed an 18% rise, could be among the potential beneficiaries. Given the wealth of experience and know-how that has accrued over the past 10 years among US shale drillers and service providers, partnerships with US companies could help China to speed up its shale oil development. But Chinese unwillingness to open up its shale industry to foreign players – as well as trade tensions with the US – is a significant stumbling block. And some US companies, including Hess and ConocoPhillips, that were initially participating in joint ventures to explore for Chinese shale pulled out years ago. Without US expertise it will take far longer for any new shale oil development to yield significant volumes. ❖

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A large proportion of the country's oil imports come with geopolitical caveats attached.

New finds show shale potential of Turkey's Thrace Basin

New discoveries in Turkey's Thrace Basin have sparked hopes of a domestic gas boom, David O'Byrne reports from Istanbul

TURKEY

WHAT:

TPAO and a JV of Valeura and Equinor have made separate finds in the basin.

WHY:

The companies are being incentivised to unearth new reserves and offset Turkey's high dependency on imports.

WHAT NEXT:

Test drilling will establish the size of the new reserves, with Ankara likely to support further development.

RECENT finds in Turkey's Thrace Basin could ignite the country's two decade-old search for substantial natural gas reserves to bolster its limited output.

The country is a major gas importer and is dependent on the substantial reserves of its neighbours, producing just 0.354 bcm in 2017, down from 0.632 bcm in 2012, while consumption in 2017 was 53.87 bcm, according to the Turkish market regulator EPDK.

Data from state pipeline operator Botas suggests that consumption was 50 bcm in 2018, with supplies coming from neighbours such as Russia and Azerbaijan.

The push to unearth new domestic reserves received a fillip last week with news of new discoveries in the Thrace Basin. Located west of Istanbul, the basin extends to the borders of Greece and Bulgaria and could become a new hotspot for hydraulic fracturing.

New finds

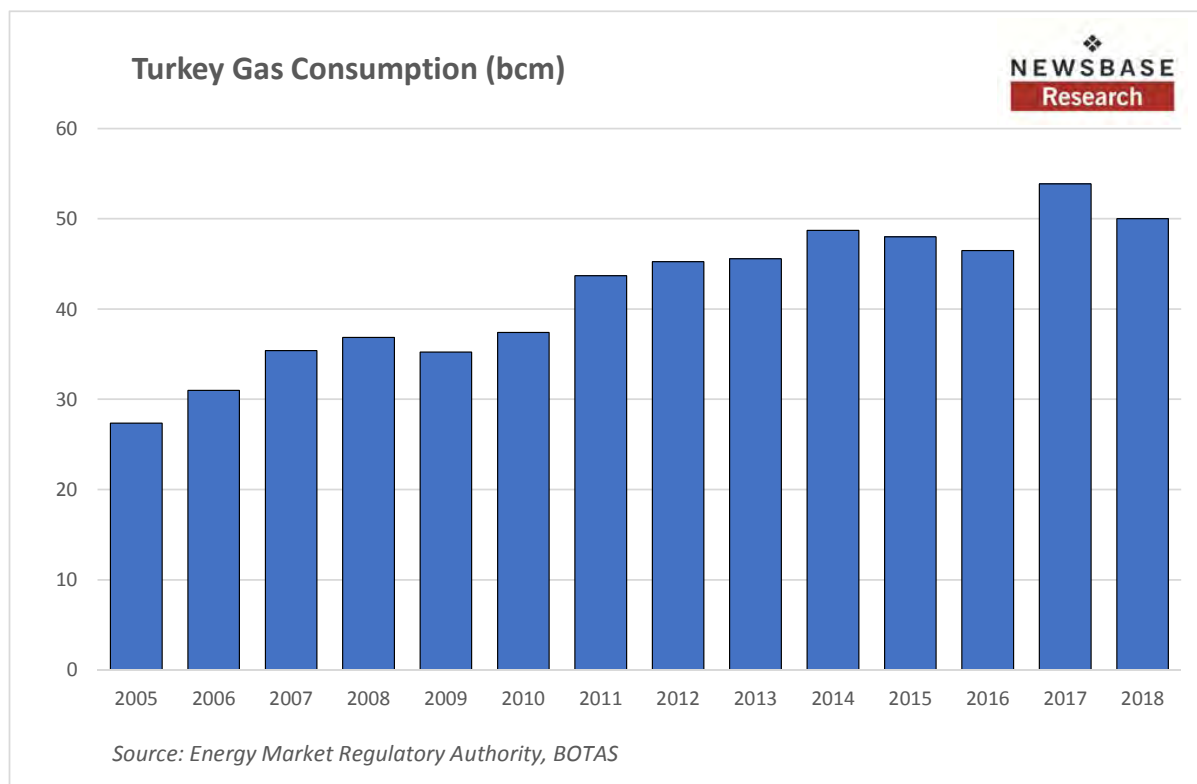
State-run Turkish Petroleum (TPAO) announced it had found gas at two new fields in Thrace – Bati Celil-1 and Bati Degirmenkoy 4-5.

Turkish Energy Minister Fatih Donmez said the two fields contained combined extractable reserves of around 3 bcm, and would be capable of producing around 0.3 bcm per year for a decade. Not a huge amount, but significant, as it would double Turkey's paltry domestic output.

TPAO's success was compounded by news of recent advances made by a joint venture (JV) between Canada's Valeura Energy and Equinor.

Valeura sold stakes in two of its licences in Thrace to the Norwegian company in 2016. The Canadian firm had previously reported that the two licences – Banarli and West Thrace, which together cover an area of 1,200 square km – held reserves of gas and condensate. But it said that, as with other discoveries in Thrace, these were at





► a comparatively shallow level.

Equinor bought into the JV saying it was interested in the possibility of deeper reserves, with its 50% farm-in being confined to finds below 2,500 metres. Valeura owns the remaining 50% stake in Banarli and 31.5% in West Thrace, with the remaining 18.5% of that concession held by Turkey's Pinnacle.

Drilling down

Equinor wants to test the basin for unconventional gas reserves, which could see fracking in the region lift off.

The first well drilled in the Banarli licence – Yamalik 1 – confirmed the presence of gas and condensate. The second well – Inanli-1 – was completed in late 2018, having been drilled to a depth of 4,885 metres. It produced gas and condensate from two sweet spots, which was sufficient for Valeura to case the well in preparation for fracking and test production.

Valeura then announced earlier in February that it would drill the Devepinar-1 well, 20 km to the west of Inanli-1, to scope out the size of the reserve that had already been identified. Initial plans are to drill to 4,300 metres, but the company has said this could be extended if results suggest the field continues deeper than estimated.

No estimate has been made about the size of the recoverable reserves, though speculation suggests they could be “substantial”.

Valeura has a stake in 21 licences and production leases in Turkey, all in Thrace, of which it operates 18. In February last year, the company said an independent evaluation of its

resources in the Thrace Basin by DeGoyler and McNaughton (D&M) had found 283 bcm of estimated working unrisks mean prospective resources, including 236 million barrels of gas condensate. Based on economic field size and the application of hydraulic fracturing technology, D&M gave the gas reserves in the basin a 74% chance of development.

Cautious optimism

There is cautious optimism the recent discoveries could prove to be commercially viable and open up the basin to industrialised fracking.

The basin shares geological similarities to US natural gas plays such as the Piceance, Uinta, Green River and Wind River Basins of the Rocky Mountains (Colorado, Utah, Wyoming), which means the region could be ripe for development.

With fracking mostly banned across Europe, pro-shale policies from Ankara could entice unconventional drilling companies to follow the lead of Valeura and Equinor and invest heavily in Turkey.

The government would be highly supportive of such a move, given the drag on the economy caused by paying for the 50+ bcm per year of gas, around half of which comes from Russia.

In a bid to attract more foreign direct investment (FDI), the government has offered a favourable 12.5% royalty rate and 22% flat net income tax rate on hydrocarbon production.

All eyes are now on how test production advances at the Thrace Basin wells and if there really is potential for a shale gas boom to ignite in Turkey. ❖

Bigger players winning Permian profitability game

Larger producers in the Permian Basin are more likely to turn profits from their wells even at lower oil prices, writes Ros Davidson

PERMIAN BASIN

WHAT:

The bigger Permian Basin producers stand to be profitable at lower oil prices.

WHY:

Major players are able to benefit from economies of scale, more drilling locations and wider financing options.

WHAT NEXT:

A growing number of DUCs needs to be completed in the Permian.

MANY wells in the Permian Basin can be profitable with oil prices as low as US\$45 per barrel, providing some relief to drillers in the region during renewed periods of price volatility. Meanwhile, larger companies can afford to drill despite lower oil prices, drawing upon their ability to operate at a greater scale. Hedging also plays a part in allowing Permian producers to keep drilling as oil prices fluctuate, and can be more efficient for bigger players. For the past few days, WTI, the US benchmark, has been hovering at US\$55.00-57.50 per barrel.

But despite the profitability of the average Permian well, the number of drilled and uncompleted (DUC) wells in the region has still been rising. The number now represents a 10-month backlog of wells, according to the most recent data from the US Energy Information Administration (EIA). This backlog is not expected to be worked through until takeaway capacity bottlenecks are fully resolved later this year, though pipeline constraints are already starting to ease.

Size matters

Still, size matters in the Permian. "You better be big, because that allows you to use economies of scale and to hedge better," a University of Texas economist, Svetlana Ikonnikova, told *NewsBase Intelligence* (NBI). She is also the co-principal investigator on the shale production and reserve study team at the university's Bureau of Economic Geology.

Some smaller companies in the Permian are struggling despite the region's prolific output growth, and are having to form joint ventures or sell acreage. "There will be more consolidation, yes definitely," Ikonnikova said.

The Permian is the world's largest tight oil production region, and also the US' most actively drilled basin. It accounts for over half the oil rigs working currently in the country, at 473 out of 853, and almost half of the total number of rigs targeting both oil and gas, which stood at 1,047 on February 22.

Rystad Energy has found that not only can about 40% of US shale projects turn a profit with oil prices at about US\$45 per barrel, but that many larger operators could also make money at US\$30 per barrel. Indeed, the

Norwegian consultancy estimates that Chevron has some wells in the Permian's Delaware sub-basin that would be profitable even at US\$20 per barrel.

However, Ikonnikova cautioned that drilling locations in the most lucrative Permian zones – the Wolfcamp A and B – were limited and might not last long if they are aggressively drilled. But new technology could change that, she added. Other formations in the multi-horizon Delaware Basin remain only marginally profitable or not profitable at all. The cost of drilling a well in the Midland sub-basin is around US\$7-9 million, while the figure is roughly US\$2-3 million higher in the deeper Delaware.

The Wolfcamp A zone is likely where Chevron has Delaware wells that are profitable at the US\$20 per barrel price, according to Ikonnikova. This crude price could also work for some wells tapping the same zone in the Midland Basin. The Wolfcamp B zone is also favoured, and able to produce high returns.

Major players

There is a consensus that the Permian is most profitable for larger companies with their own financing and access to capital markets. Larger companies have bigger positions – they have more locations to choose from, and can adjust their drilling depending on results more easily than their smaller counterparts. Apart from gains from economies of scale, larger companies can also be more efficient at hedging against oil price declines, given the resources available to them.

For smaller companies, a drop in oil prices translates to a decrease in cash and difficulties in raising capital to keep their operations going. If they are backed by private equity, the companies may need to show high returns soon, noted Ikonnikova, but for that they need good acreage and low costs. A lack of scale also often leads to higher drilling and completion costs for smaller companies, making them more vulnerable to price volatility.

In another recent study, Rystad found that operators with scaled operations and large acreage positions exposed to the Wolfcamp A in the Delaware Basin could see average returns of 20%

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There is a consensus that the Permian is most profitable for larger companies with their own financing and access to capital markets.

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- and three years' payback from new wells. This would even be the case with WTI Midland oil prices at US\$45 per barrel.

Rystad also found that out of Chevron, ExxonMobil and Anadarko, only the first appeared to have generated positive cash flow from operations in the Permian Basin in the fourth quarter of 2018. However, in a recent interview with Bloomberg, Chevron's CEO, Mike Wirth, said the Permian was on track to be cash flow positive by 2020.

Chevron has a 2.2 million-acre (8,903-square km) position in the Permian, thanks in part to its acquisition of Texaco in 2011. The super-major's production in the basin has risen 84% in the last year. And as of the last quarter, the Permian accounted for more than one in every 10 barrels of Chevron's output globally.

What next?

The Permian's contribution to US – and global – oil output will remain prominent. Crude production in the Permian recently surpassed the combined output of the Bakken and Eagle Ford – the next two most prolific tight oil plays in the US. The Eagle Ford and Bakken may see some growth now, but most likely will be back in decline in 5-8 years' time as the best drilling locations become more sparse there. At the same time, Ikonnikova and *NBI* agree that the Permian will only receive more attention.

The Permian's resource in place could be as high as 20 Eagle Fords or Bakkens. Indeed, the resource in place in only the Wolfcamp A and B zones in the Midland Basin is estimated to be 2.5-3.0 times as great as the Eagle Ford's. The Permian has 10-12 horizons that are potentially developable.

Asked about the well profitability figures for the Permian, WTRG Economics' president, Jim Williams, pointed to the soaring number of DUCs. It is an indicator of the oil differential between Midland, in the heart of the Permian, and Cushing, Oklahoma, and the bottlenecks in takeaway capacity. "None of [the operators] make any money unless they complete the DUCs," he told *NBI*.

The number of DUCs in the Permian rose from an estimated 3,965 in December to 4,170 in January, according to the EIA's most recent data. This is compared with 8,591 in December across all seven leading US unconventional regions and 8,798 in total in January. Thus the Permian accounts for almost all of the total increase in DUCs across the seven regions from December to January.

Williams also said that US\$20 per barrel oil prices would not pay for the drilling and completion of a DUC, which is about 60% of a well's total cost. Of the Permian's 609 wells drilled in January, only 404 were completed – a completion rate of roughly 66%.

"These folks are waiting for a better price – with pipelines finished in the second half of 2019 and with the Midland discount to WTI going away," he said. Williams also noted that current oil prices were not allowing for the same rapid growth in production that was seen in the Permian and other basins a year ago.

It seems that the future in the Permian will depend in part on how much a more concentrated industry can co-ordinate infrastructure development. New advances in technology that would make production from marginal horizons economic will also play a role as sweet spots are increasingly tapped. ❖

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Brazilian state edges closer to shale gas pilot

BRAZIL

THERE is new impetus for a shale gas pilot project in Brazil involving the federal government, academics and local state governments.

The scheme, first revealed in 2017, involves the drilling of a test well or wells, and is called the 'Poco Transparente', or 'Transparent Well' project.

It is scheduled to be developed in the Recan-cavo Basin in the northeastern state of Bahia, but will first have to overcome a ban on hydraulic fracturing that was introduced there in 2014.

"It is a discussion from all sectors, there are companies, there is the government, there is academia, all interested in the development of this project," said Fernanda Delgado, a professor of geopolitics in the energy department of the Getulio Vargas Foundation (FGV), a leading business school in Rio de Janeiro.

"It is a private initiative to drill and monitor various wells," she told NewsBase Intelligence (NBI) – but so far the project is focussing on gas. "You cannot attack all of them at one point, we had to choose one and we chose shale gas."

Delgado outlined the project at an FGV seminar on shale gas last week. The school has also produced a booklet on identifying and harnessing shale gas resources in Brazil.

"In creating conditions for the exploration of unconventional resources, the 'Transparent Well' will be able to present the economic benefits to society," the booklet explained, adding it would "confer credibility, sustainability and the acquisition of information".

Delgado said the idea would be to drill in the Reconcavo Basin in Bahia, regarded as one of Brazil's most promising areas for unconventional development. She said that a more open government policy towards the oil industry in recent years had helped create a "new moment" and that momentum has picked up since the election of far right President Jair Bolsonaro, who took office January 1.

"We have a new government that is clearly disposed to the use of unconventional fuels," Delgado said.

Following the seminar, Decio Oddone, director-general of the National Petroleum Agency (ANP), the Brazilian regulator, said the pilot project would "let us look not just at the economic side, but also the environmental [aspect]." In comments to the Valor Economico newspaper, he added "there are enough technological solutions today to mitigate risks."

In November former deputy energy minister, Marcio Felix, told reporters that the new



government wanted to develop unconventional reserves in Brazil. "They intend to do this. They understand why it hasn't moved forward, because there are injunctions, there are municipal laws," he said in answer to a question from NBI. Felix has been kept on by the new administration and is now secretary of oil, natural gas and biofuels at the Energy Ministry.

The state government of Bahia is the driving force behind the pilot project. "The Bahia government is mobilising to provide a safe and favourable business environment for investments in the oil and gas sector and the 'transparent well' project is a new frontier for the generation of investments and jobs in the region," a spokesman said in an email.

Lais Maciel, business development director for the Bahia government's Economic Development Secretariat, said the government was talking to private investors and government agencies to make the project viable, as it will not invest itself. "We are working with private investors to analyse where there is potential. In truth the Reconcavo has the potential for conventional and low permeability," she told NBI. "There is water, there are low permeability resources, and there is an infrastructure. We have everything there." She expressed optimism following the decision in December by a court in nearby Sergipe state that overturned a ban on fracking. Maciel said the Bahia government was talking to the ANP and prosecutors about its situation.

"In Bahia the suspension is still in effect. But we are working on other areas that go beyond shale, like tight gas, to make investment possible. Shale is just one category of unconventional," she said. "As soon as an investor appears we will have a business environment for this project." ♦

The new government in Brazil is broadly supportive of fracking.

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The government of Bahia is optimistic after a court in Sergipe state overturned a ban on fracking in December.

Indian explorer targets West Bengal shale prospects

INDIA



INDIA'S Essar Oil and Gas Exploration and Production Ltd (EOGEL) is planning a US\$1 billion project to exploit shale resources at its Raniganj East block in West Bengal, with work projected to start from 2020.

The project is awaiting approvals from Indian authorities. The block is expected to produce 7.7 tcf (218 bcm) of gas based on a field study conducted by US-based Advance Resources International (ARI), EOGEL's CEO, Vilas Tawde, told ETEnergyworld on February 20.

"We have already applied for environment clearance to drill around 20 wells as part of our exploration plan. We are also awaiting the mining lease to be amended at the state government level, post which, we can initiate work on the ground, which should approximately start in the first quarter of 2020," Tawde told the publication. He added that exploration work alone would cost around US\$30 million.

Interest in the Raniganj area has been

growing. The Indian Ministry of Environment, Forest and Climate Change's Expert Appraisal Committee announced on January 30 that it was recommending an amendment to its environmental clearance allowing 20 of 650 exploratory shale gas wells to be drilled. The committee also recommended the extension of the environment clearance for a further three years, ending on February 26, 2023.

Tawde said potential partners in the project include Oil and Natural Gas Corp. (ONGC), Great Eastern Energy Corporation Ltd (GEECL), the Central Institute of Mining and Fuel Research (CIMFR) and Geological Survey of India (GSI). He noted that a joint effort by all the players in the area would be mutually beneficial in helping to understand reservoir behaviour and map shale resources.

In 2018, the Indian government permitted oil and gas explorers to exploit all types of hydrocarbons, including shale resources, under a single licence. ♦

Texas Railroad Commission officials refute Permian flaring claims

TEXAS



TWO officials from the Railroad Commission of Texas (RRC) have rejected reports that operators in the Permian Basin are under-reporting gas flaring at a hearing of the state Senate Natural Resources and Economic Development Committee on February 20.

Ryan Sitton and Christi Craddick, two of three commissioners at the RRC, both told Senator for El Paso José Rodríguez that they believed flaring was being correctly regulated and reported to them.

"We believe the volumes reported to us are very close to accurate," said Sitton. When pressed by Rodríguez about the agency's level of regulation to prevent emissions, he added that it was "doing a good job of containing and maintaining it".

Craddick also backed the commission against claims that the flaring of associated gas production in the Permian was much higher than what had been officially reported, saying that she was "not sure if that report is accurate or not".

Last month, scientists at the Environmental Defense Fund (EDF) estimated that gas flaring in the basin was up to double the amount of reported levels. The claims were published after

the EDF compared the RRC's figures with satellite data from the US National Oceanic and Atmospheric Administration (NOAA).

The RRC is the agency responsible for regulating Texas' oil and gas industry. In the two years up to May 2018, it issued over 6,300 gas flaring permits to energy companies in the state's portion of the Permian, compared with 600 such permits for the whole of Texas between 2008 and 2010. This is largely attributed to the basin's unprecedented production growth rates.

Despite assurances from all three RRC officials, the EDF's senior manager for state regulatory and legislative affairs, Colin Leyden, remained unconvinced.

"There has to be some sort of an explanation as to why the data is not matching up," he argued. "I did not hear any sort of technical analysis of the satellite data indicating they had found any sort of flaws or errors."

However, *NewsBase Intelligence* (NBI) has previously reported that there are questions over how accurately flaring volumes might be captured by satellite imagery. Meanwhile, producers have incentives to report flaring volumes accurately. (See *UOGM Week 06*) ♦

Shell, PetroChina price dispute reportedly stalling CBM project

AUSTRALIA

A disagreement between PetroChina and Royal Dutch Shell is reportedly holding up development of their joint acreage in the Surat Basin, which contains eastern Australia's most significant coal-bed methane (CBM) resources.

The two companies are joint venture partners in Arrow Energy, which holds 5 tcf (142 bcm) of CBM in the Surat Basin, but development of the project has stalled since it was granted federal approval in 2013. Now, industry sources cited by Reuters are saying that conflicting interests have brought the companies to deadlock over Arrow's future.

As well as owning 50% of Arrow, Shell is the majority owner in Queensland Curtis LNG (QCLNG), a liquefaction plant on Curtis Island, Gladstone that would be Arrow's largest customer.

"PetroChina, as a 50% stakeholder in Arrow, expects to maximise interests from the JV versus QCLNG," an unnamed Chinese oil industry executive was quoted as saying. "But for Shell, it may be thinking of using its operator role at QCLNG to protect its interests."

PetroChina and Shell took over Arrow for A\$3.5 billion (US\$2.5 billion) in 2010 and the firm signed a 27-year supply deal with QCLNG in 2017. However, the project has stalled owing to high costs and weak gas prices in the interim and a final investment decision (FID) for the development of Arrow's Surat acreage, originally targeted for 2018, has yet to be reached. In October 2018, the company failed to sign off on a planned A\$400 million (US\$286 million) investment that would have funded 83 CBM wells in 2019.

Repairing the damage

When PetroChina bought into Arrow, it was the company's first foray into Australian CBM and was intended to become one of its major overseas assets. Instead, PetroChina reported losses of 15.5 billion yuan (US\$2.3 billion) on its share of Arrow's earnings in the five years up to 2017.

The Chinese firm is therefore eager to accelerate the project's development and maximise revenue to undo the damage done by years of delays. Reuters' source said that the investment was "already bleeding and the firm wants to cut losses, hoping not to make further bad investment decisions".

It is thought that PetroChina is dissatisfied with the price QCLNG wants to pay for CBM from Arrow's Surat project in the sales agreement. In an email to Reuters, a spokesperson for the company did not respond to questions about the alleged dispute, but said that "talks on investment and co-operation in Australia's Arrow [project] are still ongoing".



Filling a shortage

News of the alleged price spat coincided with reports that Australia's three East Coast LNG plants – QCLNG, Gladstone LNG (GLNG) and Australia Pacific LNG – all of which use CBM as feedstock, will likely never run at full capacity. There are even fears that they could be forced to shut some of their operations owing to a gas supply shortage.

The lower-than-expected productivity of CBM projects in the Surat and Bowen basins means that there is insufficient gas to feed the three plants. Concerns have emerged, for example, that QCLNG may close one of its two processing units before 2025 because of the shortfall.

While this does establish a need for additional supply that Arrow's Surat project would address, it also creates a lack of confidence in the basin's potential and the risk of QCLNG not selling as much LNG as originally predicted.

A Shell spokeswoman told Reuters that the company "supports both Arrow and QGC in developing the Surat gas project" when questioned about the gas pricing dispute. QGC is the Shell subsidiary holding the super-major's QCLNG stake.

The brakes are on

It is in the interests of both companies to move the project forward, but PetroChina and Shell have different needs when it comes to pricing. As a result, the final approval process has effectively stalled.

When Arrow and QCLNG signed the long-term supply deal in 2017, first production from the Surat project was expected in 2020. While this will now be delayed, Shell Australia's chairperson, Zoe Yujnovich, has said the company is hoping to deliver first gas just a year behind schedule, in 2021.

"It is an area we're going to have work really carefully on, particularly the Chinese approval processes, as we step through the next phase," she said in an email to Reuters.

The news service noted that Arrow deferred questions regarding investment in or the timing of the Surat project to Shell and PetroChina. ♦

“When Arrow and QCLNG signed the long-term supply deal in 2017, first production from the Surat project was expected in 2020.

Shanxi Province on CBM push

CHINA



Shanxi is one of China's two largest coal-producing provinces and has proven CBM reserves of 667 bcm.

CHINA'S northern Shanxi Province – a major coal producer – is planning to increase its coal-bed methane (CBM) output by 16% this year to 6.6 bcm per year, state media have reported.

In addition, 10 new CBM projects will be developed in the province this year, which will eventually contribute a further 2 bcm, Xinhua reported, quoting provincial authorities. No timetable for production from these projects was given.

The developments come as Shanxi also said it was tightening controls over CBM licences in an effort to prevent holders from sitting on blocks without investing enough to achieve production.

The Shanxi provincial government last week unveiled plans to tighten the management of CBM blocks to “ensure licences go to capable parties in order to boost exploration and output”, China Daily reported. This will include closer monitoring of expenditure by block licence holders.

Under contract terms, licences will be cancelled if the holders spend less than 30% of the stipulated amount over a three-year period, according to the Shanxi Provincial

Department of Natural Resources.

“The purpose of such policies is to better allocate resources under market mechanisms, allowing more capable parties to explore and exploit coal-bed methane,” the department's director of CBM, Lian Bipeng, said. “It will be difficult for mining rights holders to register coal-bed methane blocks but not make actual moves to prospect and extract the resources,” he said.

Another aim of the Shanxi government is to open up the industry to more commercial developers. Nearly 90% of its existing CBM mining rights are in the hands of a few state-owned companies, according to China Daily.

Shanxi, one of China's two largest coal-producing provinces, has proven CBM reserves of 667 bcm, Xinhua has reported. However, CBM development throughout China has been slow despite extensive national reserves.

In October 2018 the Chinese National Development and Reform Commission (NDRC) approved three CBM blocks in Shanxi. These are anticipated to yield almost 1.5 bcm per year on a combined basis when fully operational, and are expected to cost US\$1.1 billion to develop. ❖

TIGHT OIL

Targa selling stake in Bakken pipeline assets

BAKKEN



TARGA Resources is selling a 45% stake of its Bakken pipeline assets in a US\$1.6 billion deal with two private equity firms. The pipeline operator is selling its North Dakota assets – known as Targa Badlands – to funds managed by GSO Capital Partners and Blackstone Tactical Opportunities.

Targa will continue to be the operator and will hold majority governance rights in Badlands. The transaction is expected to close in the second quarter of 2019.

“Selling a minority interest in the Badlands at an attractive valuation allows us to satisfy a substantial portion of our estimated 2019 equity funding needs and provides us with significant flexibility looking forward,” said Targa's CEO, Joe Bob Perkins. The Houston-based company is one of the largest midstream operators in North America.

“Given its extensive asset footprint across the core of the highly prolific Williston Basin, we believe Badlands is well positioned for continued growth,” said GSO's senior managing director and co-head of energy, Michael Zawadzki.

The Badlands assets and operations, located in the Bakken and Three Forks plays in the

Williston Basin, include around 480 miles (772 km) of crude-gathering pipelines, 125,000 barrels of operational crude storage and roughly 260 miles (418 km) of gas-gathering pipelines.

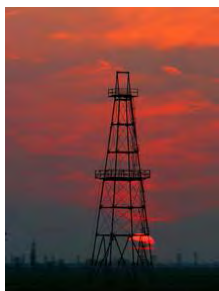
Also included in the assets is the Little Missouri gas-processing plant, which has a gross processing capacity of around 90 mmcf (2.5 mcm) per day. Additionally, Badlands owns a 50% interest in the 200 mmcf (5.7 mcm) per day Little Missouri 4 plant, which is due to be completed in the second quarter of 2019.

Targa also reported a US\$106 million loss for the fourth quarter of 2018, compared with a US\$283 million profit a year earlier. Its fourth-quarter revenues were nearly US\$2.60 billion, down from over US\$2.70 billion in the same quarter of 2017. Wall Street's fourth-quarter consensus revenue expectations had been higher, at US\$2.74 billion.

“Key projects are coming online for us in 2019, including additional gathering and processing facilities, another fractionator in Mont Belvieu, Texas, and our Grand Prix NGL pipeline, which will connect much of our [gathering and processing] NGL supply to Mont Belvieu,” said Perkins. ❖

Concho's results miss expectations

PERMIAN BASIN



MIDLAND, Texas-based shale driller Concho Resources has reported revenues for the fourth quarter that missed expectations. Analysts had expected the company, which focuses on the Permian Basin, to achieve revenue of US\$1.9 billion for the fourth quarter of 2018, but Concho fell short by a considerable margin, instead reporting US\$1.07 billion.

Nonetheless, the company reported US\$1.5 billion in profits in the fourth quarter of 2018, or US\$7.55 per share, up from a net income of US\$267 million, or US\$1.79 per share, in the same period of 2017. However, Concho's fourth-quarter 2018 adjusted net income was US\$189 million, after excluding a one-time gain of over US\$1 billion from commodity derivatives.

"Capital discipline and moderating activity" will help Concho generate more cash in 2019, the company said.

In July 2018, Concho completed its acquisition of smaller rival RSP Permian in a US\$9.5 billion merger. The company is now tightening its belt. Its capital spending for 2019 is anticipated to be US\$2.8-3.0 billion, representing a 17% reduction at the mid-point compared with the company's prior capital guidance of US\$3.4-3.6 billion. Around 94% of the 2019 capex programme will be allocated to drilling and completion

operations, said Concho.

The firm's planned activity for 2019 is anticipated to deliver oil growth of 26-30%, and the base plan for 2020 is expected to drive a two-year oil compound annual growth rate of 23% over 2018-20.

Additionally, Concho said that its base plans for 2020 would entail maintaining a consistent level of investment compared with 2019. "Prioritising capital discipline and moderating activity enhances Concho's free cash flow outlook, capital efficiency and financial flexibility," it said.

In the fourth quarter of 2018, the company's total production rose to 307,097 boepd, up from 211,083 boepd in the same quarter of the previous year. During the most recent quarter, Concho averaged 34 rigs, compared with 31 rigs in the third quarter of 2018.

The company is currently running 34 rigs, including 22 rigs in the Permian's Delaware sub-basin and 12 rigs in the Midland sub-basin. Concho is currently using just seven completion crews.

The number of drilled but uncompleted (DUC) wells has been rising fast in the Permian. This has in part been because of a sometimes wide differential between crude priced at Midland and the WTI benchmark, and also because of limited takeaway capacity. ♦

Devon in pure play tight oil drilling push

NORTH AMERICA



Selling the assets will turn Devon into a pure-play US tight oil producer.

DEVON Energy announced this week, alongside its fourth-quarter earnings, that its board has approved the sale of its heavy oil assets in Canada and in the Barnett shale gas play in the US. Selling the assets will turn Devon into a pure-play US tight oil producer.

The company said it would evaluate multiple methods of offloading the assets, including a potential sale or spin-off. It also described the move as a final step in its transformation as it shifts its focus to its "top-tier, high-return" tight oil assets.

"With our world-class US oil resource plays rapidly building momentum and achieving operating scale, the final step in our multi-year transformation is an aggressive, transformational move that will accelerate value creation for our shareholders by further simplifying our resource-rich asset portfolio," said Devon's president and CEO, Dave Hager. "New Devon will emerge with a highly focused US asset portfolio and has the ability to substantially increase returns and profitability as we aggressively align our cost structure to expand margins with this top-tier oil business. The New Devon will be able to grow oil volumes at a mid-teens rate while

generating free cash flow at pricing above US\$46 per barrel," he added.

In Canada, Devon has three oil sands facilities and some heavy oil operations in the Lloydminster area, which account for about 24% of its production.

Devon said it anticipates completing the sale by the end of this year.

A Stifel Nicolaus and Co. analyst, Derrick Whitfield, noted that investors have long been asking for Devon to dispose of its non-shale assets in the pursuit of growth. "Its top-line metrics will materially improve as a result of the divestiture," he was reported by Reuters as saying.

Devon beat quarterly production estimates on February 19, which was attributed to the strength of its shale assets. The company reported fourth-quarter production of 532,000 boepd, while analysts had expected 527,060 boepd, according to IBES data from Refinitiv. Its net income rose to US\$1.15 billion or US\$2.48 per share, from US\$304 million or US\$0.35 per share a year earlier.

In 2019, Devon expects its oil business to grow by 13-18%, despite spending 10% less on exploration and production than it did last year. ♦

EIA: shale production to hit new highs, again

US



THE US Energy Information Administration (EIA) has said it anticipates oil production in the Permian Basin to reach 4.02 million bpd in March, up from 3.98 million bpd this month. The updated figure for February is higher than the agency's previous projection of 3.85 million bpd.

The Permian, which straddles West Texas and southeast New Mexico, comprises almost half of the output in the top seven US shale regions. The EIA anticipates the combined output from these regions to hit 8.31 million bpd in February and 8.40 million bpd in March.

The most prolific tight oil region after the Permian is the Bakken, with the EIA projecting that it will yield 1.44 million bpd in February and 1.45 million bpd in March. Slightly behind this is the Eagle Ford in South Texas with an anticipated 1.43 million bpd in February and 1.44 million bpd in March, according to the agency's monthly Drilling Productivity Report, released on February 19.

In the Niobrara play, oil output is projected to be 697,000 bpd in February and 713,000 bpd next month, and in the Anadarko Basin it is expected to stay steady at 587,000 bpd over both months. The Anadarko includes Oklahoma's South Central Oklahoma Oil Province (SCOOP) and Sooner Trend, Anadarko Basin, Canadian and Kingfisher Counties (STACK) plays.

The number of drilled but uncompleted (DUC) wells in the Permian is still soaring, exacerbated by the basin's lack of takeaway capacity. Permian DUC counts rose from an estimated 3,965 in December to 4,170 in January according to the latest data.

DUCs grew by an estimated 29 in the Eagle Ford from December to January, from 1,568 to 1,597. But they dropped by 22 – from 529 to 507 – in the Appalachia region, which holds the Marcellus and Utica shale plays, during the same time period.

Across all the leading tight oil regions, DUC counts hit 8,591 in December and 8,798 in January. The Permian thus accounts for almost all of the total rise in DUCs across the seven regions.

The EIA projects that natural gas production in the Appalachia region will reach 31.29 bcf (886 mcm) per day this month, and 31.60 bcf (895 mcm) per day in March. This accounts for about 40% of the total across the seven regions, which is forecast to reach 77.11 bcf (2.18 bcm) per day this month and 77.97 bcf (2.21 bcm) per day in March.

The second most productive shale region for natural gas is the Permian – where natural gas is a by-product of oil drilling – with output projected to reach 13.18 bcf (373 mcm) per day in February and 13.40 bcf (379 mcm) per day in March. ❖

NEWS IN BRIEF

POLICY

Fracking moves forward in Colombia

Ecopetrol has applied for permit from Colombia's National Environmental Licences Authority that will allow it to conduct the first pilot in fracking in the Middle Magdalena, Portafolio reported.

According to the paper, technical and scientific personal from Ecopetrol – after several years of studies – will carry out a pilot project in an area that is 50 to 60 km wide and 150 km long.

Ecopetrol expects to begin work next year and said there could be several pilots in the zone, which is near the Cesar-Rancheria Basin. It did not specify the investment or the specific area as that will be determined by the government.

The aim is that the pilot provides the necessary information to allow the country to establish the necessary guidelines for this type of exploration.

SHALE GAS

US, Swiss companies partner to supply frack sand to Argentina

Louisiana-based Shale Support has entered into an agreement with Switzerland-based transportation company Fracht Group to export sand for hydraulic fracturing to operators in Argentina's Vaca Muerta shale play.

The oilfield services company sent its first shipment from New Orleans on February 18, and it is due to arrive in Argentina on March 10. From there, the sand will be transferred via truck to the firms' co-managed distribution warehouse in the Vaca Muerta region.

"With Fracht Group's current shipping business into South America and Shale Support's geographic proximity to the Gulf Coast, we are able to provide quality proppant to Argentina without the traditional operational challenges of supply and logistics,"

Shale Support's CEO, Kevin Bowen, said in a statement.

Cuadrilla asks to alter fracking fluid used at Lancashire site

Cuadrilla Resources has applied to alter the hydraulic fracturing fluid it is using at its site at Preston New Road in Lancashire, England. The company has halted operations on the site since before Christmas and is now looking to deploy a host of new additives in the fracking fluid it uses which is injected under pressure deep underground.

"The reason for the proposed variation is that we'd like to modify our fracturing fluid so that more sand can be carried into the shale rock with the water when we re-commence hydraulic fracturing operations at the Preston New Road site," Cuadrilla's environment manager, Nick Mace, said.

"To do this we propose to add some





► chemicals which have already been approved for use elsewhere in the UK by the Environment Agency,” he added.

“The fracturing fluid will remain non-hazardous to groundwater, as it must do under UK regulation, and additional additives we are proposing to use are commonly found in food, toiletries and other products used around the home.”

However, anti-fracking group Frack Free Lancashire said: “We are concerned, but not entirely surprised, that after years of claiming that the only two chemicals to be used in UK fracking were polyacrylimide and hydrochloric acid, that they should now be seeking, after just one failed frack, to expand the list of chemicals.”

The group added: “Equally concerning is the list of 41 potential additives to their drilling fluids of which no less than 14 are described by Cuadrilla themselves as ‘potentially hazardous.’”

Matador Resources announces midstream transaction expanding San Mateo’s operations in the Delaware Basin

Matador Resources today announced a second strategic midstream transaction with a subsidiary of Five Point Energy to expand San Mateo’s natural gas gathering and processing, salt water gathering and disposal and oil gathering operations in the Delaware Basin to be owned in the same proportions as San Mateo I – 51% by Matador and 49% by Five Point. As part of the expansion, an additional cryogenic natural gas processing plant will be constructed in close proximity to the existing Black River cryogenic natural gas processing plant near Carlsbad, New Mexico in Matador’s Rustler Breaks asset area.

The existing Black River Processing Plant was placed into service in August 2016 with

a designed inlet capacity of 60 million cubic feet of natural gas per day. In February 2017, San Mateo I was formed as a joint venture owned 51% by Matador and 49% by Five Point. The Black River Processing Plant was then expanded to a designed inlet capacity of 260 million cubic feet of natural gas per day in April 2018. Today, this plant is already almost fully subscribed. This new transaction is the next step to almost doubling that capacity to meet growing natural gas processing demand in the area. With this new transaction, San Mateo plans to expand its natural gas pipeline system to run from the Black River Processing Plant north to Matador’s Stebbins leasehold area and south to Matador’s new Stateline asset area that was acquired in connection with the Bureau of Land Management New Mexico Oil and Gas Lease Sale in September 2018. The additional salt water gathering and disposal and oil gathering facilities will be variously located across Matador’s Eddy County, New Mexico acreage, additional portions of which will be dedicated to San Mateo.

To facilitate this transaction and add economies of scale, Matador dedicated to San Mateo acreage under 15-year, fixed-fee contracts in the Stebbins and surrounding acreage in the Arrowhead asset area as well as Matador’s Stateline asset area – totalling approximately 25,500 gross acres.

MATADOR RESOURCES, February 25, 2019

TIGHT OIL

Permian Basin crude inventories hit four-month low as new pipelines start production

Crude stocks in West Texas fell to a four-month low during the week of February 18 as new and converted gas pipelines increased the level of crude transported from the Permian Basin to the US Gulf Coast, according to data

from Genscape.

The market intelligence provider showed there was a drop in storage in the US’ biggest tight oil region as increased takeaway capacity reduces bottlenecks, which have been affecting local crude prices and filling up storage tanks.

Inventories fell to the lowest since October 2018 to 15 million barrels, down from the record-high of 22 million barrels.

Stocks started to decrease following the start-up of Plains All American Pipeline’s Sunrise Pipeline expansion, which increased the project’s capacity by 300 000 bpd. And Enterprise Products Partners started transporting crude on a converted natural gas liquids (NGLs) pipeline – the 200,000 bpd Seminole-Red project – two months ahead of schedule, helping to accelerate the drawdown.

New Mexico lease sale nets US\$35 million

The Land Office New Mexico State reveals that the oil & gas lease sale of February 2019 has netted more than US\$35 million. This includes the largest open bid sale in the firm’s history, with numerous tracts in southeastern New Mexico closing at more than US\$12 million.

Most of the money generated by the State Land Office is used for the public education and other beneficiaries.

New Mexico is continuing to see the benefits of the boom in the Permian Basin, which straddles parts of New Mexico and West Texas, the Land Commissioner Stephanie Garcia Richard said.

The United States is expected to pump 12.4 and 13.2 million barrels of oil per day in 2019 and 2020 respectively. Permian Basin is expected to add the maximum amount.

Pioneer Natural Resources announces CEO Tim Dove to retire; chairman Scott Sheffield to return as CEO

Pioneer Natural Resources today announced that Timothy L Dove will retire as CEO and a board director effective immediately. Scott D Sheffield, chairman of the board, will return to his former role as chief executive officer.

Scott was Pioneer’s founding CEO, serving from 1997 to 2016, and has served as chairman since 1999. Lead director, J Kenneth ►►

► Thompson, will become chairman of the board, also effective immediately.
PIONEER NATURAL RESOURCES, February 21, 2019

QEP reports fourth-quarter results

Shale producer QEP Resources has reported a net loss of US\$629.3 million – or US\$2.66 per diluted share – for the fourth quarter of 2018. This marks a drop from income of US\$150.3 million – or US\$0.62 per share – in the same quarter of 2017. The company noted that the loss includes impairment charges of US\$1.2 billion, which stem from the deal it struck to sell Williston Basin assets. The loss also includes a US\$12.3 million increase in administrative expenses and a US\$10 million decrease in net loss from asset sales, which is inclusive of restructuring costs. However, QEP added that the loss was partially offset by a US\$469.5 million increase in gain on derivative contracts, a US\$19.9 million drop in lease operating expenses (LOEs) and a 10% rise in oil and condensate output.

The company produced 11.6 million boe during the fourth quarter of 2018, down from 12.1 million boe a year ago. This marks a drop of 4%. QEP's gas output fell by 18%, while its oil production was up 10% and condensate and NGL production rose by 4% year on year. The firm said decreased Williston Basin oil production, lower gas output from the Haynesville/Cotton Valley plays and the sale of its Uinta Basin assets had all had a negative impact on its production figures.

Diamondback announces fourth-quarter results

Diamondback Energy reported on February 19 that for the whole of 2018, it achieved net income of US\$846 million, or US\$8.06 per diluted share – up from US\$482 million, or US\$4.94 per share a year ago. Its adjusted net income was US\$615 million, or US\$5.87 per diluted share, and for the fourth quarter, Diamondback reported adjusted net income of US\$148 million, or US\$1.21 per share.

The company said its fourth-quarter production reached 182,800 boepd, comprised of 71% oil. This marked an increase of 49% over the previous quarter and a rise of 97% year on year.

Diamondback has announced production guidance of 275,000-290,000 boepd for 2019, with oil anticipated to account for 68-70% of this. Such a rate would mean over 27% growth year on year.

However, the company has lowered its 2019 capital expenditure budget for drilling, completion, midstream and infrastructure to US\$2.7-3.0 billion. Diamondback anticipates completing 290-320 gross horizontal wells over the course of the year.

ExxonMobil to increase Permian profitability through digital partnership with Microsoft

ExxonMobil said today a new partnership with Microsoft will make its Permian Basin operations the largest-ever oil and gas acreage to use cloud technology and is expected to generate billions in net cash flow over the next decade through improvements in analyses and enhancements to operational efficiencies.

The application of Microsoft technologies by ExxonMobil's XTO Energy subsidiary – including Dynamics 365, Azure, Machine Learning and Internet of Things – is anticipated to improve capital efficiency and support Permian production growth by as much as 50,000 oil-equivalent barrels per day by 2025.

"The combination of Microsoft's technologies with our unique strengths in oilfield technologies, production efficiency and integration will help drive growth in the Permian and serve as a model for additional implementation across the U.S. and abroad," said Staale Gjervik, senior vice president, Permian Integrated Development for XTO. "The unconventional business is fast moving, complex and data rich, which makes it well suited for the application of digital technologies to strengthen our operations and help deliver greater value."

ExxonMobil's partnership with Microsoft includes an integrated cloud environment that securely and reliably collects real-time data from oil field assets spanning hundreds of miles.

The data will enable ExxonMobil to make faster and better decisions on drilling optimization, well completions and prioritization of personnel deployment. Importantly, leak detection and repair response times could be further reduced with enhanced access to emissions data, strengthening XTO's voluntary actions to manage methane emissions.

ExxonMobil's application of these technologies in its Permian Basin acreage, which covers a 9.5 billion oil-equivalent barrel resource base and more than 1.6 million acres, represents industry's largest acreage position using cloud technology.

EXXONMOBIL, February 22, 2019

Sanchez Energy to be delisted from NYSE

The New York Stock Exchange (NYSE) has started the process to delist Houston-based Sanchez Energy Corp (SEC).

The Houston oil firm was removed from the exchange after failing to submit a plan to meet the minimum market capitalisation requirement, which was due by February 19, 2019.

Formal paperwork for Sanchez to be delisted is expected to be filed as early as March 7, 2019.

The delisting will make it harder for the company to raise money, attract investors and obtain financing, Sanchez Energy Interim Chief Financial Officer Cameron George said in a filing on February 20, with the U.S. Securities and Exchange Commission.

George said that there was no assurance of ►►



► exactly when trading would commence or if there would be an active market for its stock there.

Highlands Natural Resources Colorado shale — East Denver wells IP rate announcement

Highlands, the London-listed natural resources company, is pleased to announce that oil production rates from the pad at its East Denver project have achieved an initial production rate of 4,600 boepd during the flow-back period.

Highlands expect that the oil and gas production rate will increase as the choke size is increased.

HIGHLANDS NATURAL RESOURCES, February 25, 2019

Stockholders of Resolute Energy approve merger with Cimarex Energy

Resolute Energy today announced that at a special meeting of stockholders held earlier today, Resolute's stockholders voted to approve the adoption of the merger agreement between Resolute and Cimarex Energy.

15,950,431 shares voted in favour of the proposal to adopt the merger agreement. This represents approximately 85% of the total shares of Resolute's common stock represented and entitled to vote at the special meeting, and more than 99% of the votes cast, excluding those stockholders who abstained from voting on the merger proposal.

Resolute will file the final vote results

with the Securities and Exchange Commission on a Form 8-K.

As previously announced, on November 18, 2018, Resolute and Cimarex entered into the merger agreement by which Cimarex will acquire Resolute in a cash and stock transaction.

With the receipt of the required stockholder approval, Resolute and Cimarex expect to close the transaction on March 1, 2019, subject to satisfaction of the remaining customary closing conditions.

RESOLUTE ENERGY, February 22, 2019

Quintana Energy Services provides preliminary fourth-quarter 2018 results

Quintana Energy Services today announced preliminary fourth-quarter 2018 results.

Fourth quarter 2018 revenue is expected to range between US\$158.1 million to US\$161.3 million, fourth quarter 2018 net loss is expected to range between US\$(1.8) million to US\$(1.5) million and fourth quarter 2018 adjusted EBITDA is expected to range between US\$13.2 million to US\$14.5 million.

In the fourth quarter, QES weathered a tough macro environment and is expecting to record a 6% sequential increase in revenue, a 31% sequential decrease in net loss and an 8% sequential increase in adjusted EBITDA.

Rogers Herndon, QES president and chief executive officer, stated: "I'm pleased to report that revenue increased sequentially at three of our four segments despite the market headwinds experienced in the fourth quarter. The sequential increase in revenue was largely driven by increased utilisation in our directional drilling segment, and increased utilisation and stages pumped in our pressure pumping segment, offset by reduced pricing

driven by market dynamics. The sequential decrease in net loss and increase in adjusted EBITDA was largely driven by improved results in our directional drilling segment.

"Additionally, we deployed two incremental large diameter coiled tubing units and executed on our previously announced wireline segment reorganisation late in the fourth quarter and believe the benefits of this reorganisation will prove out in the first quarter of 2019. We will discuss our results and market outlook in more detail when we release earnings on March 6, 2019."

QUINTANA ENERGY SERVICES, February 25, 2019

CBM

Tlou starts production testing of its Botswana project

Australian Tlou Energy announced on February 25 that it has started production testing at its Lesedi 3 coal-bed methane (CBM) development in Botswana.

The pods are being de-watered and the pressure in the coal seam is being lowered to support gas flow to eventually allow power supply.

The firm has also completed drilling operations on its Lesedi 4A lateral well and the operations on its Lesedi 4 well are ongoing, whilst the drilling of the second lateral well, Lesedi 4B, is the final well in the current drilling phase.

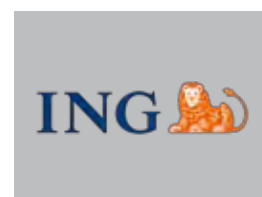
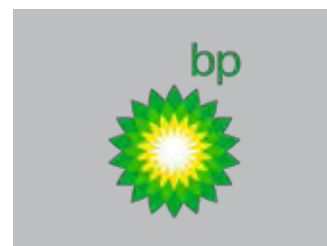
All wells in the field, which has been developed since late 2018, are being drilled as 'dual lateral pods'.





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